ALBERTA UTILITIES COMMISSION

IN THE MATTER OF

ALBERTA ELECTRIC SYSTEM OPERATOR (AESO)

2014 ISO TARIFF APPLICATION
AND
2013 ISO TARIFF UPDATE

APPLICATION NO.: 1609765
PROCEEDING ID NO.: 2718

EVIDENCE
OF POWER ADVISORY LLC
(JOHN DALTON AND
TRAVIS LUSNEY)

On behalf of

THE OFFICE OF THE UTILITIES CONSUMER ADVOCATE
(UCA)

I. INTRODUCTION

Q 1. Mr. Dalton, please state your name, business address, and the nature of your business.

A 1. My name is John Dalton. I am President of Power Advisory LLC (Power Advisory). My business address is 212 Thoreau Street, Concord, Massachusetts. Power Advisory is a management consulting firm focusing on the electricity sector and specializing in electricity market analysis and strategy, power procurement, energy policy development, litigation and regulatory support, and electricity project feasibility assessment.

Power Advisory's clients include power planning and procurement agencies, regulatory agencies, generation project developers, transmission companies, consumer advocates, non-governmental organizations and electric utilities.

Q 2. On whose behalf are you testifying in this proceeding?

A 2. I am appearing on behalf of the Office of the Utilities Consumer Advocate (UCA).

Q 3. What is your professional and academic background?

A 3. I am an electricity market analyst and policy advisor with over 25 years of experience in the electricity sector. I specialize in energy market analysis, electricity policy analysis and development, power procurement and contracting, generation and transmission project evaluation, and strategy development. I am experienced in the evaluation and analysis of electricity markets and the competitiveness and operation of various generation technologies and transmission projects within these markets.

I have performed studies evaluating transmission access issues across Canada and the U.S. and advised clients on policies to promote the efficient development of transmission facilities to enable renewable energy project development, the design of transmission tariffs, transmission pricing issues, the appropriate framework for the development of merchant transmission facilities, and pros and cons of different transmission company business models.

I have testified on behalf of Hydro One Networks Inc., the largest transmission company in Ontario, regarding the appropriateness of a network charge determinants approach proposed by an industrial consumer group. I was the project manager and lead consultant for Power Advisory's work assisting the Ontario Energy Board (OEB) staff in their transmission connection cost responsibility review. I have testified regarding transmission investment analysis methods.

I advised the OEB on its proceeding regarding "enabler transmission" lines by drafting a report that summarized the elements of California's Renewable Energy Transmission Initiative and Texas' Competitive Renewable Energy Zones. I advised the staff of the OEB on the evaluation of a 1,250 MW HVDC line between Quebec and Ontario and two 230 kV transmission lines to alleviate a major Ontario transmission constraint. I was the project manager for various assignments on the East West Transmission grid on behalf of the Canadian Energy Ministers and subsequent work with the Federal-Provincial-Territorial Electricity Transmission Working Group and Natural Resources Canada.

I have served as a consultant to the electricity sector for over 25 years with various firms and prior to this served as an economist with the Massachusetts Energy Facilities Siting Council. Prior to this, I served as an economist with the Massachusetts Department of Environmental Protection where I assisted with the costing of emission control initiatives that were targeted at electric utilities and major industrial facilities.

I have a BA in Economics from Brown University and an MBA from Boston University. I have taken courses in resource planning methods and regional planning at the Massachusetts Institute of Technology and Boston University. A copy of my curriculum vitae is attached as Appendix JD-1.

Q 4. Have you testified before a tribunal or court to provide expert evidence?

A 4. Yes. I have testified in over twenty proceedings across North America on issues ranging from transmission pricing policy, the need for and comparative economics of new electric generating facilities, standard-offer programs for the procurement of renewable energy and capacity, electric utilities' competitive procurement programs, wholesale electricity market prices, and the likely competitiveness of wholesale power markets.

Q 5. Have you appeared before the Alberta Utilities Commission (Commission)?

A 5. No. I have not formally testified before the Commission. However, I did offer Written Evidence before the Commission on behalf of TransCanada Energy Ltd. in the Alberta Electric System Operator's (AESO's) Competitive Process Application (Proceeding ID No. 1449). I also testified before the Alberta Energy and Utilities Board (AEUB or the Board) in the Transmission Congestion Management Principles proceeding (EUB 2002-099) about eleven years ago.

Q 6. Please briefly review your evidence in the Transmission Congestion Management Principles proceeding.

A 6. I outlined a proposal where transmission investments would be measured against the benefits that they produced and where the rate impacts to customers was measured against "quantifiable benefits" to these customers. If the rate impact to transmission customers less quantifiable benefits from these facilities was less than 5 to 10 percent then the cost of these transmission facilities would be rolled into the existing rate base. If the rate impact after consideration of these benefits was greater than 10% then a contribution would be required from the customer who triggered the investment.

This testimony aligns reasonably well with subsequent Government Policy as reflected in the *Transmission Regulation* (174/2004) and as subsequently amended (86/2007) (attached hereto for convenience as Appendix JD-2), which promoted the development of transmission facilities that enable generation development.

Q 7. Mr. Lusney, please state your name, business address, and the nature of your role at Power Advisory.

A 7. My name is Travis Lusney. My business address is 55 University Avenue, Suite 600, Toronto, Ontario. I am a Senior Consultant at Power Advisory.

Q 8. What are your qualifications?

A 8. I have Bachelor of Science and Master of Science degrees in Electrical Engineering from Queen's University. I am a licensed Professional Engineer. I have over 7 years of experience in the electricity sector and have worked at an Ontario electric distribution company as a distribution planning engineer and the Ontario Power Authority in system planning. I have attached a copy of my curriculum vitae as Appendix TL-1.

Q 9. What is your relevant experience in the electric utility sector?

A 9. I have previously worked as both a distribution and transmission engineer with expertise in the areas of generation development, power system planning, business strategy, and risk assessment. Before joining Power Advisory I worked as a Transmission Planner in Power System Planning at the Ontario Power Authority (OPA) where I was actively involved in regional integrated planning, bulk system analysis and supporting system expansion studies, resource procurements and regulatory proceedings. When I left the OPA I was a Senior Business Analyst in the Generation Procurement Department where I was responsible for management and development of the Feed-In Tariff program. Prior to the OPA I worked for Hydro Ottawa Limited as a Distribution Engineer responsible for reliability analysis, capital planning, power system capacity assessment and project management.

Q 10. Have you testified before?

A 10. No, I have not.

II. PURPOSE, SCOPE AND SUMMARY OF EVIDENCE

Q 11. What is the purpose of the Power Advisory written evidence?

A 11. Power Advisory was engaged by the UCA to provide an expert opinion on whether transmission facilities being developed in Alberta have been triggered by objectives other than to reliably serve peak demand and, if so, to evaluate the role that these "other" objectives played in supporting the development and construction of these facilities. Such transmission facilities have come to be called "Special Projects". We were also asked to provide an expert opinion on an appropriate approach to recover the costs of such facilities from customers. The cost recovery for Special Projects was excluded from the Settlement Agreement[1] entered into by the parties to this Proceeding (ID No. 2718).

Q 12. What is the scope of the Power Advisory written evidence?

A 12. We first review at a high level the AESO's 2014 ISO Tariff Application and then review the policy and regulatory framework for transmission development in Alberta. We then review policies employed in other North American jurisdictions which align with some of the issues posed by Special Projects in Alberta. Finally, we offer a definition of Special Projects and identify transmission projects that could be considered Special Projects. Finally, we recommend an approach for designating transmission projects as Special Projects and for recovering the costs of such projects.

Q 13. Please briefly summarize your written evidence.

A 13. The *Transmission Regulation* significantly expanded the criteria used to identify when new transmission facilities are needed, from reliability-based considerations to projects that are needed to avoid transmission congestion. This promoted the development of a new class of transmission projects, which have become known as Special Projects. Special Projects are transmission projects developed to address one or more of the following needs or objectives:

[1] Exhibit 0120.03.AESO-2718, section 22 (c)

- Enable renewable energy integration and access to the Alberta Interconnected Electric System (AIES);
- Enable uncongested dispatch of generation under normal operating conditions;
- Interconnect additional generation to enhance competition and market efficiency; and
- Promote Government and public policies.

We recommend that five transmission projects, treating the East HVDC and West HVDC projects as one project, be designated as Special Projects given that they are being built, at least in part, to enhance market performance and efficiency. With different determinants of need than reliability-based transmission projects, it is appropriate that the costs of Special Projects be recovered using a different approach. The average & excess method is an appropriate cost recovery approach for Special Projects given that it recognizes that costs are driven by both energy and demand requirements. It is typically used to allocate demand-related generation costs, e.g., baseload generation which provides fuel cost savings, where higher fixed costs are incurred to achieve lower energy costs. Special Projects are driven by similar objectives, promoting the development of a competitive market and improving transmission system efficiency. Establishing a separate designation for Special Projects and allocating their costs on the basis of the average & excess method will provide more efficient price signals to Alberta customers and by so doing result in better investment decisions.

III. REVIEW OF AESO APPLICATION AND SETTLEMENT AGREEMENT

Q 14. How are wires costs recovered from classes of customers under the AESO's current tariff?

A 14. Under the AESO's current tariff bulk and local wires costs are recovered using demand (82% of costs) and energy charges (18% of costs). By comparison, the portion of bulk and regional wires costs that are classified as energy-related in the Settlement Agreement is just 5%. These costs were classified as demand and energy-related using the minimum system approach. Demand related costs are recovered using the 12 Coincident Peak (CP) method.

In response to an AESO proposal in its 2007 GTA to recover almost 50% of wires costs in an energy charge, the Board found that "transmission wires costs are largely fixed in nature and most appropriately recovered primarily through demand charges."[2]

Q 15. What are the implications of the magnitude of planned transmission investment in Alberta on the AESO's tariff application?

A 15. The total revenue requirement of the TFOs wires is projected to increase by 189% from \$648 million in 2010[3] to \$1,875 million in 2016[4], representing almost a 20% compound annual growth over this period. Furthermore, with this increase in revenue requirements driven by major new transmission projects, the proportion of these costs functionalized as

[2] Decision 2007-106, p. 30
[3] Decision 2010-606, p. 5
[4] Exhibit 0012.00.AESO-2718, Appendix J, Tab "Rates", row 16, Columns H and J

bulk system costs is projected to increase from 41.7% in 2010[5] to 60.0% in 2016[6], causing bulk system costs to increase from $270 million to $1,124 million.

These bulk system costs are allocated to customer classes largely based on their demand during the peak hour in each month (i.e., the 12 CP) regardless of what drove the need for the different transmission facilities or the types of benefits that they provide customers.

IV. TRANSMISSION DEVELOPMENT IN ALBERTA

Q 16. What is the policy and regulatory framework that guides transmission development in Alberta and should be considered when evaluating cost recovery for transmission facilities?

A 16. Transmission development in Alberta is guided by the *Transmission Regulation*. The *Transmission Regulation* was preceded by the transmission development policy (policy) presented in *Transmission Development: The Right Path for Alberta* (attached hereto as Appendix JD-3). As outlined in the policy, the *Transmission Regulation* seeks to ensure that transmission constraints are not a barrier to generation development and market access and development in Alberta and gives greater weight to this objective than most other competitive markets in North America. The *Transmission Regulation* was first issued in 2004 and amended in 2007. Transmission planning provisions in the 2007 amendments expanded the *Transmission Regulation*'s scope.

[5] Exhibit 0002.00.AESO-2718, AESO Application, p. 29
[6] Exhibit 0120.03.AESO-2718, Settlement Agreement, at para 11

Most other organized competitive markets in North America employ Locational Marginal Prices, which provide clear locational signals. In contrast, Alberta has a uniform price across the province, which provides no locational signal. Given the Alberta market's relatively small size, ensuring that transmission constraints are not a barrier to generation development and market participation is critical.

Q 17. Please briefly review the *Transmission Regulation*.

A 17. The *Transmission Regulation* outlines the required framework for transmission system planning, including the criteria for determining when additional transmission facilities are needed. The AESO must plan a transmission system that, in addition to satisfying reliability standards, is sufficiently robust to allow transmission of 100% of anticipated in-merit energy when all transmission facilities are in service and 95% of all anticipated in-merit energy under abnormal operating conditions.[7] In addition, the 2007 amendments allowed the AESO to assess the contribution of proposed transmission facilities to: "(ii) a robust competitive market; (iii) improving transmission system efficiency; (iv) improving operational flexibility; (v) maintaining options for long term development of the transmission system."[8]

Q 18. How is the policy relevant given that it is not formally binding?

A 18. The policy provides guiding principles for transmission system development in Alberta. The *Transmission Regulation* implements this policy and provides direction for transmission planning and the development of Alberta's transmission infrastructure. The

[7] Appendix JD-2, *Transmission Regulation*, AR 174/2004, s. 8 (e); and AR 86/2007, s. 15 (e), pdf p.10 and p.41
[8] Appendix JD-2, *Transmission Regulation*, AR 86/2007, s. 8 (d), pdf p.34

guiding principles outlined in the policy provide insights to the objectives of the *Transmission Regulation* and the growing role of Special Projects in Alberta.

Alberta Energy noted that the "fundamental goal of the transmission policy is to ensure that consumers are served with reliable, reasonably priced electricity, and to support continued economic growth in Alberta."[9] The policy was based on the principle that transmission development must balance the costs and benefits of the facilities and that benefits include greater system reliability, future resource development, increased market liquidity, more competitive pricing, and lower price volatility.

Recognising the importance that transmission plays in supporting new generation development, the policy paper asserted that "transmission should not be a barrier to generation development – investors should be provided with certainty and confidence that transmission will be developed in a timely and adequate manner so that their product can be transported to market."[10]

The policy was premised in part on the fact that transmission accounted for a relatively small proportion of a typical customer's bill. With the transmission projects under development, this will be less true in the future.

Q 19. Does the *Transmission Regulation*, the accompanying policy direction and their implications for the level of transmission investment warrant consideration of different cost recovery approaches than a framework where transmission is built primarily to reliably serve load?

[9] JD-3, p. 2 of 19, pdf p. 3 of 20
[10] Ibid

A 19. Yes, they do. The AESO is directed to make transmission investments for reasons other than just maintaining system reliability. Transmission investment is also now required to: (1) integrate intermittent renewable energy resources, which are not being built to provide firm power; (2) integrate conventional fossil and non-intermittent renewable (e.g., biomass) generation resources; and (3) alleviate or avoid transmission congestion. Clearly, this policy direction results in a significant change in the transmission investment drivers and causes the AESO to pursue the development of transmission projects for new reasons. This is demonstrated by the increase in number of Special Projects, which can be viewed as a product of the *Transmission Regulation*. Therefore, it is appropriate to reconsider how the costs of transmission facilities that are built for reasons other than to reliably serve load are recovered from customers, particularly given the magnitude of investment represented by such facilities.

Q 20. What principles has the regulator applied in past decisions regarding transmission rates?

A 20. The Commission has employed the oft-cited Bonbright principles, which the Commission's predecessor Board identified in its 2007 Decision on the AESO's 2007 GTA as:

(i) Recovery of the total revenue requirement;

(ii) Provision of appropriate price signals that reflect all costs and benefits, including in comparison with alternative sources of service;

(iii) Fairness, objectivity, and equity that avoids undue discrimination and minimizes inter-customer subsidies;

(iv) Stability and predictability of rates and revenue; and

(v) Practicality, such that rates are appropriately simple, convenient, understandable, acceptable, and billable.[11]

The Board noted that the first three principles should be given primary consideration and the last two secondary consideration.[12] These rate design principles provide valuable guidance on the appropriate considerations for establishing cost recovery for Special Projects in Alberta.

V. TRANSMISSION FACILITY COST RECOVERY PRECEDENTS

Q 21. Have other ISO/RTOs and regulators in North America implemented such changes in cost recovery where there have been corresponding changes in the transmission investment criteria?

A 21. Yes. A number of ISO/Regional Transmission Organizations (RTOs) and regulatory commissions have recognized that the drivers of transmission projects in their respective jurisdictions have changed and that the corresponding basis for cost recovery for non-reliability driven transmission projects should also change.

We focus on two examples: (1) the U.S. Federal Energy Regulatory Commission (FERC), which amended its transmission planning and cost allocation requirements in Order No. 1000 issued in July 2011; and (2) the California Independent System Operator (CAISO) which has distinguished between different types of transmission solutions in its transmission planning and outlined different cost recovery approaches for these (CAISO

[11] Principles of Public Utility Rates by Bonbright, Danielsen, and Kamerschen, 2nd ed., 1988, pp. 385-389 (as cited in AEUB Decision 2007-106, pp. 12-13)
[12] AEUB Decision 2007-106, p. 14

Comprehensive Transmission Planning Process Document, attached hereto as JD-4). For a number of these transmission solutions it recovers the costs of bulk transmission facilities through an energy charge (i.e., $/MWh).

Q 22. Please discuss the relevant aspects of FERC Order No. 1000 for establishing a cost recovery approach for Special Projects in Alberta.

A 22. FERC required that transmission providers consider transmission needs driven by public policy requirements in their transmission planning processes and participate in a regional transmission planning process that has an inter-regional cost allocation method for the cost of new inter-regional transmission facilities. FERC also directed RTOs and ISOs to demonstrate that their cost allocation methods for new inter-regional transmission facilities satisfy six principles. The two most relevant to Special Projects are:

> "(1) The cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits. In determining the beneficiaries of transmission facilities, a regional transmission planning process may consider benefits including, but not limited to, the extent to which transmission facilities, individually or in the aggregate, provide for maintaining reliability and sharing reserves, production cost savings and congestion relief, and/or meeting public policy requirements established by state or federal laws or regulations that may drive transmission needs."[13]

[13] FERC Order 1000, p. 421

"(6) A transmission planning region may choose to use a different cost allocation method for different types of transmission facilities in the regional plan, such as transmission facilities needed for reliability, congestion relief, or to achieve public policy requirements established by state or federal laws or regulations."[14]

In support of the first principle, FERC found that "requiring a beneficiaries pay cost allocation method or methods is fully consistent with the cost causation principle as recognized by the Commission and the courts."[15]

With respect to the sixth principle, FERC noted that "the one factor that it weighs when considering a dispute over cost allocation is whether a proposal fairly assigns costs among those who cause the costs to be incurred and those who otherwise benefit from them. Therefore, it is appropriate here to adopt a cost allocation principle that includes as beneficiaries those that cause costs to be incurred or that benefit from a new transmission facility."[16] FERC noted that the development of the cost allocation method for inter-regional facilities "rests with the public transmission providers participating in regional transmission planning processes in consultation with stakeholders."[17]

Q 23. Can you expand on FERC's rationale as to why it found that a beneficiary pay approach is appropriate?

A 23. Without such an approach FERC found that there was a potential for "free riders". Admittedly, there is a greater potential for free riders for inter-regional transmission

[14] Ibid, pp. 423-424
[15] Ibid, p. 448
[16] Ibid pp. 448-449.
[17] Ibid p. 489

facilities. Specifically, the customer of a transmission owner that does not finance and construct the facilities may benefit from their construction, but may make no contribution to their cost absent such a FERC mandate. There is a similar issue and potential for cross subsidization in Alberta if there are significant benefits from a transmission facility and the allocation of benefits among customers is not reflected in the cost recovery. For example, if a new transmission facility is required primarily to interconnect new generation projects which otherwise would not be developed and these projects enhance the competitiveness of the market and result in reductions in the pool price, then the benefits will be realized by customers based on their participation in the energy market rather than their demand during monthly system peaks. This suggests that recovering a portion of the cost of these transmission facilities on the basis of an energy charge is more appropriate than solely on the basis of a demand charge.

Q 24. What policies and approaches has the CAISO employed that are relevant to the treatment of Special Projects in Alberta?

A 24. In its transmission planning, the CAISO has recognized that there are distinct categories of projects and where appropriate employs different cost recovery approaches for these projects.

With respect to transmission planning, the CAISO has established six categories of "transmission solutions": (1) Merchant Transmission Facility Proposals, which are undertaken on a merchant basis, with cost recovery risks borne by the proponent, not the customers of the transmission utility where the facility is located; (2) Reliability Driven Solutions, which are transmission projects that are required to ensure system reliability consistent with planning standards; (3) Location Constrained Resource Interconnection Facility (LCRIF) Projects, which are transmission projects undertaken to interconnect generation resources, primarily wind and solar, in transmission constrained locations; (4) Large Generator Interconnection Process (LGIP) Network Upgrades, which are triggered by generator interconnection requests; (5) Policy-Driven Transmission Solutions, which are transmission solutions needed to meet state, local or federal policy requirements, such as the state's Renewable Portfolio Standard; and (6) Economic Studies and Mitigation Solutions, which are transmission solutions that are needed to address congestion and integration of new generation resources and can be justified on the basis of production cost savings, congestion cost reductions, transmission loss reductions, and reduced capacity or other electric supply costs resulting from improved access to cost-efficient resources.

Cost recovery for the merchant transmission facilities is the responsibility of the project developer. The costs of LCRIFs are allocated to load until the Location Constrained Resource connects. Once the Location Constrained Resource connects to the transmission network it pays for its contribution to the LCRIF based on its maximum capacity relative to the total capacity of the LCRIF.

Other than these two types of transmission solutions, the CAISO recovers all of the costs of bulk transmission facilities that have had their operational control turned over to the CAISO as a uniform $/MWh charge for all loads. Both California and Alberta have a competitive electricity market and an independent system operator. We consider the California example as a relevant precedent for recovering the costs of special transmission projects in Alberta using an energy charge.

VI. PROPOSED APPROACH FOR SPECIAL PROJECTS

Q 25. What are Special Projects?

A 25. There is no formal definition for Special Projects. However, in general terms Special Projects are transmission projects driven by factors other than serving growth in peak system demand. In its report, "Alberta Transmission System Cost Causation Study",[18] London Economics International LLC (LEI) defined special projects as "projects which are clearly driven to interconnect renewable energy or driven by reliability purposes, but not primarily driven by load".[19] While their costs should not necessarily be recovered on the basis of 12 CP given that they are needed as a result of non-peak operating conditions (e.g., voltage stability), these projects are not necessarily Special Projects. For example, a project that is built to address a voltage concern, previously would have been identified by the AESO as needed for system reliability and assigned to a TFO to build. It would not necessarily be triggered by the requirements of the *Transmission Regulation*.

LEI also suggests that special transmission projects can be triggered by public policy objectives.[20]

[18] Exhibit 0120.04.AESO-2718
[19] Ibid, p. 77
[20] Ibid

Q 26. How do you recommend that Special Projects be defined?

A 26. We recommend that Special Projects be defined as transmission projects developed to address one or more of the following needs or objectives:

- Enable renewable energy integration and access to the AIES, excluding any interconnection assets that are appropriately allocated to generators;
- Enable uncongested dispatch of generation under normal or abnormal operating conditions pursuant to the *Transmission Regulation*;
- Interconnect additional generation to enhance competition and market efficiency; and
- Promote Government and public policies.

The first three of these items are planning objectives that focus on enhancing market performance and efficiency and seek to promote the objectives embodied in the *Transmission Regulation*. The fourth item, promoting Government Policy, recognizes that the need for transmission projects pursued to promote government policies may not be affected by peak demands.

Q 27. If a project is deemed to be a Special Project should its costs be recovered in the same manner as the costs of projects built to reliably serve load?

A 27. No. We recommend that a different cost recovery approach be used for Special Projects. The costs for transmission projects that are built to reliably serve load are recovered primarily based on customers' contributions to peak loads, i.e., the 12 CP method. Special Projects satisfy other needs and their costs should be recovered more broadly and in a manner that is more in line with what drives the need. Specifically, the three planning objectives identified above enhance the performance of Alberta's competitive energy market or provide benefits to customers participating in that market. The recovery of the costs of transmission facilities built to further these objectives on the basis of energy consumption is more appropriate than on the basis of customers' peak demand. Therefore, we recommend that a portion of the costs of Special Projects, or the costs of a project that are deemed "special", be recovered on the basis of energy consumption and an energy charge.

Q 28. Transmission projects are often developed to satisfy multiple objectives. In your opinion is any project which satisfies one of the objectives or needs identified above appropriately considered a Special Project?

A 28. Not necessarily. We propose that three tests be applied to determine if a project is to be deemed special.

(1) Where a project would not be undertaken, but for the need to satisfy one of these planning objectives or Government Policy then we believe that the project should be deemed to be "special". For example, where a project is designed to reduce congestion within a region and increase market efficiency by reducing constraints to economic dispatch of generation, the ability to serve peak load in the region is unchanged but the efficiency of operation within the region is increased, the project should be treated as "special".

For Government Policy triggered projects to be deemed special, their need should not be peak demand driven.

(2) Where a project is undertaken to address system reliability, but the ultimate form of the project (e.g., configuration) is determined or strongly influenced by one of these planning objectives or Government Policy then it may be appropriate to deem a portion of the project's costs to be special. For example, where a project's design is determined by one of these planning objectives and this design increases the project's overall cost, the incremental cost triggered by this planning objective could be treated as "special".

(3) Where a project is undertaken to address system reliability, but offers significant other benefits, a portion of the costs should be considered "special".

Q 29. Are you recommending that there be separate cost pools for a project where a portion of its costs are deemed special?

A 29. No. Such an approach would be too burdensome administratively, at the current time. Rather than attempt to determine the portion of project costs that are appropriately deemed special and then to functionalize these costs as special, we recommend that a cost allocator be used which recognizes that a portion of the costs of Special Projects are typically energy-driven and a portion demand-driven.

Q 30. On what basis do you recommend that the costs of Special Projects be classified between energy and demand charges?

A 30. We propose that the costs of Special Projects be classified on the basis of the average & excess (A&E) method. The AESO proposed using the A&E method to allocate bulk and local wires costs in its 2007 GTA application.[21] The Board rejected the use of the A&E

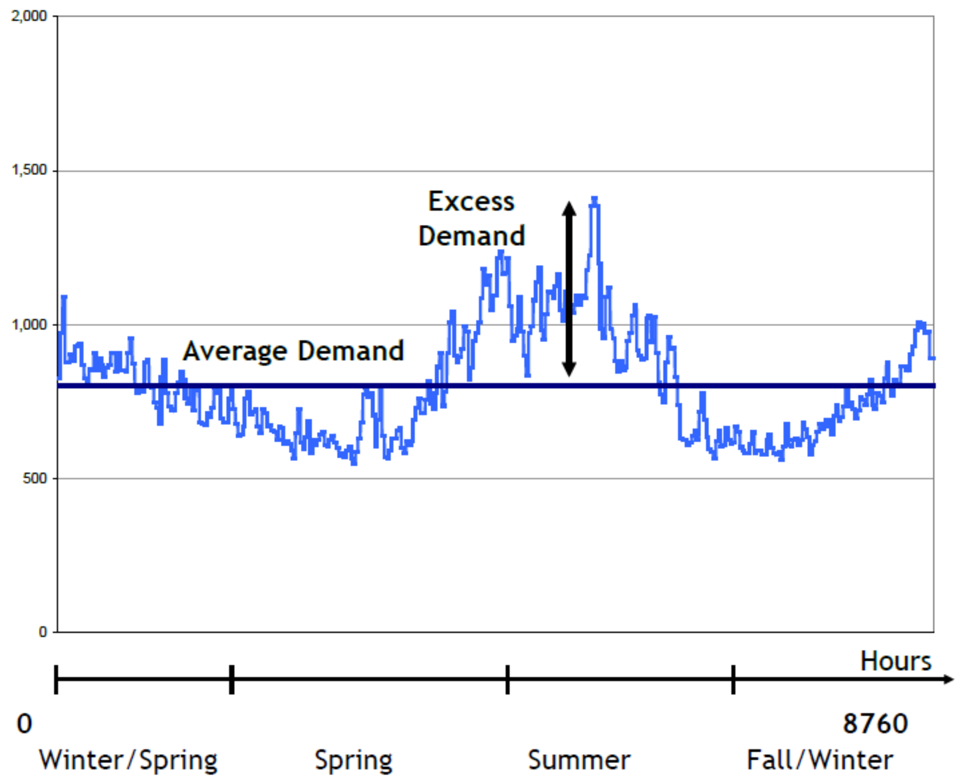
[21] Application 1485517

method in its decision approving the AESO's GTA application with modifications[22], accepting the arguments posed by various parties that opposed this method. One criticism of A&E method was that it was generally used "to allocate generation costs, and a methodology used for generation is not necessarily warranted for allocating transmission costs."[23] Using the A&E for cost recovery for Special Projects is different.

Q 31. Please describe the A&E method.

A 31. The A&E method is a demand-related cost allocator, which recognizes that a portion of fixed costs are energy-related and the remainder demand-related. Under the A&E, the energy-related component of fixed costs is established based on the system load factor and the demand component is allocated using excess demand. This is shown in the following figure. A range of measures of demand (i.e., 12 CP, NCP, CP) can be used.

[22] Decision 2007-106
[23] Ibid, p.28



Source: Brattle Group, Issues in Cost Allocation, EEI Advanced Rates School, University of Wisconsin, Madison, 2011

Q 32. How do you respond to the Board's assertion at page 30 in 2007-106 that "transmission wires costs are largely fixed in nature and most appropriately recovered primarily through demand charges"?

A 32. We acknowledge that wires costs are largely fixed. However, for Special Projects the primary contributors to the need for the projects are not demand-related. Growth in peak demand does not drive the need for most Special Projects, growth in energy requirements typically drives the need. Therefore, it is appropriate to recover a portion of these projects costs through an energy charge.

The A&E method implicitly recognizes that both energy requirements and demand drive the need for the facilities to which it is applied and is commonly used to allocate generation demand-related costs for baseload generation facilities. The A&E recognizes that higher fixed costs are incurred to achieve lower energy costs. In essence, this is what drives Special Projects. The energy allocation is based on the average demand. Therefore, the proportion of the total fixed costs allocated to energy is based on the load factor, with a customer class's energy related cost responsibility based on the total energy requirements of the class.

Q 33. Why not employ a project specific cost recovery approach for each Special Project?

A 33. A case can be made that the appropriate energy and demand weighting should vary by project, with a project such as SATR warranting a higher energy weighting than the East and West HVDC facilities. From this perspective, the A&E method is an approximation of the appropriate cost responsibility.

The respective energy and demand related benefits of Special Projects could be quantified in an effort to establish such weights. While this approach is intuitively appealing since in theory cost allocation would more closely follow cost causation, establishing cost causation for such facilities is difficult and imprecise. Furthermore, implementing such an approach would require significant resources, with the range of plausible assumptions providing a wide range of outcomes. Therefore, employing such an approach to determine cost recovery is not appropriate at this time.

Q 34. How did you assess whether projects should be considered Special Projects?

A 34. We reviewed all projects in the AESO's Long-term Transmission Plan filed June 2012, and attached hereto as Appendix JD-5, (LTP) with costs greater than $100 million. These are the same projects reviewed by LEI and represent approximately 91% of the total cost of all planned projects in the LTP. In addition, we reviewed projects that were identified in the *24-Month Reliability Outlook (2010-2012)*, which was Appendix B to the LTP[24]. To ensure a more thorough review of the project investment drivers information from the relevant Needs Identification Documents (NIDs) also was reviewed.

Q 35. Based on this review and the criteria outlined above which projects should be considered Special Projects?

A 35. Based on the information provided on bulk transmission system projects in the LTP and NIDs, we recommend that the following planned and recently constructed transmission projects should be designated Special Projects according to the criteria identified above.

- Southern Alberta Transmission Reinforcement (SATR) Project
- East HVDC and West HVDC Projects
- Foothills Area Transmission Development (FATD) Project
- Wabamun Lake/Keephills Ellerslie Genesee (KEG) and Edmonton/Fort Saskatchewan Bulk Transmission Projects
- Northwest Transmission Developments

Elements of the FATD project have a commercial operation date after 2016, but as a result of Construction Work in Progress (CWIP) may have costs that are reflected in the AESO's current Tariff Application.

Q 36. Why do you believe that the SATR should be designated a Special Project?

A 36. The SATR project is primarily needed for integration of renewable generation, in particular wind. The LTP states that the project is required to "meet the needs of the

[24] Attached as JD-8

existing and proposed (wind) generation"[25] The SATR NID states: "The need for transmission reinforcement in southern Alberta is driven predominantly by the forecast development of wind generation."[26] The SATR NID also indicates that "The consequences of inadequate transmission in southern Alberta will be that the wind interest cannot be integrated into the AIES without violation of the AESO Reliability Criteria."[27] Both documents indicate that the project would not be built, but for the need to integrate wind generation. Importantly, wind generation does not typically operate at high levels at the time of system peak. An analysis of wind generation and load data for 2012 showed that the correlation coefficient between the output of wind generators in Alberta and the Alberta system load is only about 0.08, showing a very low relationship between wind generation and demand. The AESO's *2012 Market Statistics Report*, attached hereto as Appendix JD-6, indicates that average capacity factor for Alberta wind projects at the time of the AIES system peak over the last five years has been 19%.[28]

LEI also identified SATR as a Special Project.[29]

Q 37. What drove the need for the Edmonton to Calgary system reinforcements and the decision to utilize HVDC technology?

A 37. The East HVDC and West HVDC transmission expansion projects address multiple needs and the HVDC design promotes a number of objectives. The AESO's 2009 Long-term Transmission System Plan, attached hereto as Appendix JD-7, (LTTSP) indicated

[25] Appendix JD-5, *AESO 2012 Long Term Transmission Plan*, p. 86
[26] SATR NID, Application 1600862, Proceeding ID. 171, Exhibit 0001.00, p. I, PDF p. 9
[27] Ibid, p. 17, PDF p. 34
[28] Appendix JD-6, AESO 2012 *Market Statistics Report*, p. 17
[29] Exhibit 0120.04.AESO-2718, p. 78

that reinforcement of the transmission system between Edmonton and Calgary was needed to address future reliability issues in south and central Alberta. In addition, the LTTSP also found that "using high capacity HVDC transmission lines makes most efficient use of rights-of-way and minimizes land-use impacts. While a number of factors and conditions are considered in making this technology choice, including consultation, economics and efficiency, a priority is given to minimizing land-use impacts in support of government policy as presented in the Provincial Energy Strategy."[30] The *Transmission Regulation* also requires that "the ISO must consider (a) wires solutions that reduce or mitigate the right of way, corridor or other route required, and (b) maximizing the efficient use of rights of way, corridors or other routes that already contain or provide for utility or energy infrastructure."[31]

In sum, the need to reinforce the Edmonton to Calgary transmission corridor was driven primarily by reliability considerations and the decision to employ HVDC technology was in response to a number of objectives, the most important being to minimize land-use impacts.

Q 38. What are the non-reliability benefits of these facilities that justify them being deemed Special Projects?

A 38. The non-reliability benefits include:

- Improving the efficiency of the transmission system;
- Restoring the capacity of existing interties;

[30] Appendix JD-7, *AESO 2009 Long Term Transmission System Plan*, p. 37
[31] Appendix JD-2, *Transmission Regulation*, AR 86/2007, s.15.1 (2), pdf p.42

- Avoiding congestion, which prevents the market from achieving a fully competitive outcome;
- Promoting the development of new competitive generation in the Edmonton area and further north, which were being slowed by transmission congestion;
- Reducing transmission losses; and
- Controlling power flow to manage contingencies, which can maximize the efficiency of the transmission paths.[32] (p. 80)

Given that the non-reliability related benefits of the East and West HVDC projects are significant, we believe that they should be considered a Special Project.

Q 39. On what basis do you believe that the FATD project should be treated as a Special Project?

A 39. The LTP indicates that "the FATD project is an integral part of the system required to move wind energy to the load centres of the Foothills and greater Calgary area."[33] The LTP also indicates that "in addition to integrating wind energy, the Foothills area development provides other benefits by creating a system that will accommodate potential gas-fired generation in and near the City of Calgary, as well as mitigating local transmission constraints within the city to facilitate future load growth."[34] The AESO's FATD Plan NID indicated that "the AESO's 2009 Long-term Transmission System Plan identified transmission reliability constraints in the South Calgary Area that would arise

[32] Appendix JD-5, *AESO 2012 Long Term Transmission Plan*, pp. 79-80
[33] Ibid, p. 89
[34] Ibid

within the 2014 to 2019 timeframe"[35] As further discussed in the FATD Plan NID the required transmission facilities are needed for both system reliability requirements and to accommodate additional generation.

Q 40. Why do you believe that the transmission system developments associated with the Keephills 3 interconnection and reconfiguration of the Edmonton 240 kV lines should be designated a Special Project?

A 40. The AESO's *24-Month Reliability Outlook (2010-2012)*, attached hereto as Appendix JD-8, lists a variety of transmission system developments required as part of the interconnection of the Keephills 3 generator and related reconfiguration of the Edmonton 240 kV lines. These transmission developments are expected to remove or reduce congestion in the AIES. The *Keephills Unit #3 Interconnection Need Identification Document*[36] identifies the transmission system constraints resulting from the interconnection of Keephills 3 and summarizes the system additions and enhancements proposed to resolve these constraints. In the NID, the AESO states that the transmission system developments will resolve voltage stability, dynamic stability and thermal overloading constraints. The transmission developments would also address reliability concerns associated with 3 phase faults that could result in the Genesee/Keephill generation cluster separating from the system. By resolving these constraints the transmission system upgrades would allow uncongested dispatch of the Genesee/Keephill generator cluster under normal operating conditions and improve market efficiency. This qualifies the project as a Special Project. The transmission system developments are

[35] FATD Plan NID, Application 1608620, Proceeding ID 2001, p. 1, PDF p. 3
[36] Keephills Unit #3 Interconnection Need Identification Document, Application 1584342

driven by the unconstrained integration of generation into the AIES and not due to growing peak demand.

Q 41. Why do you believe that Northwest Region transmission system developments should be designated a Special Project?

A 41. The Northwest Region is a load pocket with over 1,100 MW of load, but about 800 MW of generation, The AESO has contracted for Transmission Must Run (TMR) service to ensure that a minimum amount of generation stays online to ensure power transfers into the region are kept within operating limits.[37] In the *24-Month Reliability Outlook (2010-2012)*, the Northwest Region transmission system developments are justified by addressing voltage stability and voltage collapse concerns along with reducing the dependence of area load on TMR services. The Northwest Alberta Transmission Development NID[38] prepared in 2006 by the AESO states that the transmission development plan would address the voltage collapse concerns and reduce the dependence on TMR services. The reduction of TMR services would reduce uneconomic dispatch of generation and therefore increase market efficiency and enable uncongested dispatch of generation under normal operating conditions and supports the designation of the Northwest Region transmission development as a Special Project.

Q 42. In your opinion in what forum should the determinations of whether a transmission project is a Special Project be made, and by whom?

A 42. We believe that these determinations should be made by the AESO as part of its NID filing with the Commission. The NID filing could be expanded to make such a

[37] Appendix JD-8, *AESO (24-Month Reliability Outlook (2010-2012), p. 13*
[38] Northwest Alberta Transmission Development NID, Application 1581966

qualitative determination as to whether a project was a special project or a portion of its costs was deemed to be special.

However, for the five Special Projects that we have identified in this Evidence, we recommend that the Commission find them to be Special Projects.

Q 43. Do you have an estimate of how your proposed identification and treatment of Special Projects would affect the functionalization and classification of transmission system costs?

A 43. Yes, we do. This is presented in the table below. For this estimate we have assumed a 50/50 energy/demand cost classification given that the data required to establish the energy and demand weights for the A&E method were not available to us. The actual results provided by the A&E method could be determined by the AESO.

Functionalization and Classification of Transmission System Costs
(Per Cent of Total)

		Classification		
Function	**Total**	**Demand**	**Usage**	**Customer**
2014 ISO Tariff				
Bulk System	44.8%	41.3%	3.5%	-
Regional System	24.1%	20.5%	3.6%	-
Point of Delivery	22.2%	*to be determined from POD cost function*		
Special	8.9%	4.4%	4.4%	-
2015 ISO Tariff				
Bulk System	48.4%	44.6%	3.8%	-
Regional System	21.7%	18.4%	3.2%	-
Point of Delivery	19.1%	*to be determined from POD cost function*		
Special	10.8%	5.4%	5.4%	-
2016 ISO Tariff				
Bulk System	48.1%	44.3%	3.8%	-
Regional System	20.6%	17.6%	3.1%	-
Point of Delivery	18.7%	*to be determined from POD cost function*		
Special	12.6%	6.3%	6.3%	-

Q 44. What are the benefits to Alberta of your proposed approach to treat Special Projects as a separate class of transmission facilities with their costs to be classified as energy and demand related using the A&E method?

A 44. This proposed approach best satisfies the Bonbright principles. It would result in the appropriate price signals by recovering a portion of Special Project's costs in an energy charge. This is more efficient than recovering all of these costs from demand charges given that these projects are built in part for the benefits that they provide to Alberta's competitive energy market. Such a cost responsibility is also more equitable and avoids inter-customer subsidies that could otherwise be possible if high load factor customers avoid monthly peaks and reduce their cost responsibility under the 12 CP method. The A&E method is also a practical approach, which avoids the need to attempt to determine the specific portion of project benefits that are appropriately categorized as energy-related and those which are demand-related.

The more efficient price signals from recovering a portion of Special Project's costs on the basis of energy consumption will promote more efficient investment decisions, with a portion of cost responsibility based on an energy charge rather than entirely on a demand charge.

Q 45. Please summarize your recommendations.

A 45. We offer four recommendations:

(1) a special class of transmission facilities be established, which we refer to as Special Projects.

(2) the designation of Special Projects be based on whether they address one or more of the following objectives: (a) enable or facilitate the integration of generation projects to the AIES; (b) enable the uncongested dispatch of generation under normal or abnormal operating conditions pursuant to the *Transmission Regulation*; or (c) improve market efficiency.

(3) the five Special Projects identified in this evidence be designated as such by the Commission and in the future, the AESO be responsible for designating Special Projects, with stakeholders able to challenge that designation as part of the NID review before the Commission; and

(4) the costs of Special Projects be classified on the basis of the average & excess method.

Q 46. Does this conclude your written evidence?

A 46. Yes.